ER 96 Testimony on:

ACTIONS NECESSARY TO PROMOTE RELIABILITY

Prepared for the July 11, 1996, ***ER 96*** Committee Hearing

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June 11, 1996

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Part II

Are the Predicted Pool Prices Which Would Result from the CPUC Proposal [and the WEPEX Filing] Provide Incentives for Sufficient Market Entrance to Maintain a Reliable Power Supply, and What Actions Should Be Taken to Avoid or Mitigate Adverse Effects of the Proposed Market Structure and to Foster Beneficial Ones?

A. Introduction

In jointly filed testimony (Part I), staff discussed various aspects of electricity-system reliability and identified several ways in which electricity-industry restructuring may adversely affect reliability. That staff testimony addressed three areas of reliability: (1) operating, (2) transmission, and (3) generation. For each of these, staff discussed both how the California Public Utilities Commission (CPUC) decision's[1] proposed market structure may affect reliability and how the Western Power Exchange (WEPEX) filing's[2] proposed market structure, ostensibly conforming to the CPUC decision, would affect reliability differently. Finally, the staff identified areas where reliability may be an issue during the transition and/or in the long term.

This testimony addresses three areas in which either the CPUC decision or the WEPEX filing fails to provide effective incentives for investment in generation, transmission and/or other energy services. It identifies changes to the proposals to create or improve incentives; the incentives it covers include: locational pricing, transmission-congestion contracts and customer-driven reliability targets. Finally, it discusses what actions should be taken to promote reliability and by whom.

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[1]CPUC Decision 95-12- as modified by Decision 96-01-

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[2]Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, Docket Number ER96-1663-000.

B. Location-Specific Energy Prices

In Part I, staff noted that, to encourage transmission investment, the CPUC proposes locational pricing and a system of transmission-congestion contracts (TCCs),[3] which the ISO would administer. According to the CPUC-proposed market structure, the Power Exchange would pay generators *location-specific* market-clearing prices, but it would charge Power Exchange consumers a *system-wide* price.

The CPUC-proposed pricing approach would dull any incentive for customers to act in an economically efficient way based on different location-specific prices. Furthermore, since Utility Distribution Companies (UDCs) and Direct Access providers (DAs) would also face only a system-wide Power Exchange price, they have little incentive to act on their customers behalf based on locational-price differences. This may significantly affect the ability of new market entrants to find consumers willing to contract for services outside the Power Exchange. Presumably, only those customers who would cost less to serve than the average system-wide energy price would be willing to sign such contracts. This kind of incentive has the effect of targeting (physical and financial) direct access at the lowest-cost-to-serve customers rather than at all customers for whom less expensive options are available, and, in turn, raising the system-wide price over time.

Staff also noted that—in some important situations—WEPEX (in the PG&E-SCE-sponsored version) does not plan to pay generators locational market-clearing prices. Specifically, when transmission congestion arises within a transmission

[3]We note here that TCCs were not proposed for purposes of encouraging, and probably would not encourage, transmission expansion. Rather, they are one of the necessary incentives to add economic generation, given the potential for locational-price differences to emerge between a generator and its customer(s). Section C, below, discusses how this mechanism is intended to work.

zone,[4] according to the PG&E-SCE-sponsored approach, the ISO would dispatch up a more expensive generator within the congested area and dispatch down a less expensive generator outside the congested area.[5] PG&E and SCE propose to pay the constrained-on generator its bid price but pay all other generators the market-clearing prices determined before the ISO-imposed constraint. The difference between the constrained-on generator's bid price and the market-clearing price would be applied to all grid customers as an uplift.

This intra-zonal pricing approach differs from inter-zonal pricing in two important ways. First, it pays two generators situated in the same location differently if the ISO has dispatched one of them to manage intra-zonal congestion. Second, it collects the congestion-management costs from all grid-use customers, rather than just from those located in the congested area.

The PG&E-SCE approach creates two perverse incentives. To begin with, since only the constrained-on generator is compensated for being located in a congested area, all similarly situated generators will have the incentive to bid just below the constrained-on generator so they can be similarly compensated.[6] In addition, generators in the unconstrained area and grid-use customers throughout the affected zone face inefficient pricing. Generators in the constrained-off area should

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[4]WEPEX defines four transmission zones in California within which transmission congestion has historically either not occurred frequently, or not occurred at all.

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[5]This is the way utility control-area operators relieve congestion today, and it is also the way SDG&E proposes to relieve congestion.

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[6]This incentive for generators to game their bids provides the rationale for paying all generators the market-clearing price.

face a lower market-clearing price that reflects the value of generating in that area. Instead, this inefficient incentive potentially encourages new generators in a location where, at the same time, transmission limitations constrain the output of existing, economic generators. Constraining these existing generators could reduce their revenues sufficiently to force them to go out of service.

Similarly, consumers should face different market-clearing prices on either side of the transmission constraint reflecting the difference in the value of consuming in the two areas. Since consumers on the constrained-off side of the grid face higher prices than they should, they may respond by reducing their consumption, making the congestion conditions worse.[7] At the same time, since consumers in the constrained-on area face prices lower than they should, they may increase their consumption, raising market-clearing prices for everyone.

While the presence of perverse incentives in this approach to intra-zonal pricing potentially encourages inefficient investments, there are no incentives to encourage efficient investments, such as transmission upgrades, or new, properly placed generation and load, to relieve the congested line. Thus, reliability can be threatened (in this case, in the congested area) by the lack of efficient incentives.

C. Transmission-Congestion Contracts

Transmission-Congestion Contracts (TCCs) are financial instruments intended to provide their holders with a form of price certainty. Part I noted that the CPUC

[7]That is, by consuming less in the uncongested area, even cheaper generation may be curtailed because lower demand reduces the point on the loading order where local demand clears. By "worse" we mean the actual economic cost of relieving congestion increases.

decision directs utilities to propose an ISO-administered system of TCCs to help encourage investment in transmission expansion. As we discussed above, TCCs may not encourage investment in transmission upgrades and may instead, if properly implemented, discourage unnecessary transmission investments.[8] They may encourage investment in new generation by allowing investors to hedge against the locational-price differences between that new generator and its customers.

Investors, looking to invest in a new generator, could face unacceptable risk if they were to contract with customers to deliver power *to the customers' facilities* at a given price. The risk arises whenever the proposed generator and its customers' loads are located at different points on the grid. In such cases, those consumers may incur congestion charges due to the transfer limits between the two locations.[9] However, without power-sales contracts with customers, investors have no assured revenue stream and, therefore, incur the risk that they may not recover their investment. By acquiring TCCs, a generator is able to cover the risk of locational-price differences. In return for purchasing TCCs, their holders will receive any transmission-congestion revenues collected from customers.

While the CPUC directed the utilities to propose a system of ISO-administered TCCs, the SCE-PG&E version of the WEPEX filing defers that action until such time as

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[8]James Bushnell and Steven Stoft of the University of California Energy Institute have discussed some circumstances in which TCCs may encourage parties to remove certain beneficial lines from service or to add certain detrimental lines. They identify some mitigating options for further study. "*Transmission and Generation Investment in a Competitive Electric Power Industry*," May 10, 1995.

[9]This risk is present whether or not a customer holds a "physical" direct-access contract.

market participants demand them. They argue that private markets may develop TCCs if, or when, they are needed. Given utilities' argument, a fair question is: "Why is it necessary to have the ISO administer a system of TCCs rather than allowing private markets to emerge?"

Those who advocate ISO-administered TCCs argue that they are necessary because only the ISO can determine a set of simultaneously feasible TCCs, and the ISO collects the transmission-congestion revenues from customers. Unless the ISO administers such financial instruments, they may fail to exhibit the properties necessary to fully hedge against price differences without a significant risk premium.

There are numerous and significant issues associated with TCCs, and they will take a concerted effort to resolve. Among these are: how to accumulate an initial, simultaneously feasible set of TCCs; how to allocate the initial set of TCCs; how to reallocate TCCs when modifications to the network take place; and how to discourage inefficient transmission modifications, e.g., by redistributing TCCs. TCC proponents generally assume that existing ratepayers are the initial TCC holders, but their holdings are presumably not location specific, i.e., ratepayers have the obligation to pay for the entire existing transmission system, not any specific portion of it. For TCCs to provide the incentive they are proposed to provide, we will need to address these issues well in advance of the time new investments are planned. In staff's judgement, failure to provide ISO-administered TCCs to hedge against locational-price differences, and to conduct the foundational work to institute them, erects a significant entry barrier for new generators. Whether this is primarily an economic issue or also threatens reliability is unclear, at present.

D. Load Bidding

According to both the CPUC proposal and the WEPEX filing, the Power Exchange would conduct a daily energy auction. Winning bidders in the auction would receive at least their bid price for energy, and, unless they set the market-clearing price, they would receive more than their bid price. Bidders will presumably use the difference between their bid price and the market-clearing price to cover their fixed costs and any remainder would become profit. A number of people have observed that this bidding mechanism may cause our currently hefty capacity-reserve margins to shrink because those generators which operate infrequently will be unable to recover all of the costs they incur to stay in service.[10] Thus, perhaps rapidly,[11] utilities and other generators will begin to retire low-capacity-factor generating units in order to cut their losses. This could eventually lead to the situation where reserve margins are inadequate to maintain load-resource balance under high-demand conditions.

At a recent conference in Sacramento, one presenter[12] observed that there are two ways to assure that sufficient capacity is available to meet the reliability needs of consumers at all times:

- Carry sufficient reserves to meet the appropriate reserve criteria and pay

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[10] While the CPUC will allow utilities to recover the return of, and on, past investments through a Competitive Transition Charge, this will not cover the cost of fixed operating and maintenance expenses.

[11] How rapidly reserves shrink will depend on the degree to which ancillary service payments contribute to generator viability. The ability of a few generators to provide scarce ancillary services may present the opportunity to exert market power in the combined market. In such cases, capacity reserves may not shrink so rapidly.

[12] ***May 16-17, 1996, MAPS Users' Conference; "Modeling Competitive Electricity Markets with MAPS,"*** by Scott Harvey, Putnam, Hayes & Bartlett, Inc.

generators an administratively determined capacity payment so they can cover their fixed costs as well as their variable costs.

- Have sufficient load response to assure that demand bidders will set the market-clearing price.

The first approach closely follows the current practice of setting reserve-margin targets to ensure reliability. It also suffers from the same short comings, i.e., those special interests who can afford to participate in the process of setting a reserve target, and allocating the costs of maintaining it to consumers, have a better opportunity to manipulate that process to their benefit, leaving other interests at risk for picking up a greater share of the costs.

The second approach relies on consumer-driven decisions to establish the appropriate level of reliability, and compensates generators by allowing the price of energy during times when capacity is scarce to become very high by conventional standards. There are several concerns with this approach, however. First, it relies on demand responsiveness which may not be well developed when the new market structure begins to operate. It also suffers from a potential political vulnerability because electricity consumers are accustomed to paying cost-based prices, rather than whatever the market will bear. There are also potential vulnerabilities to this approach for systems which rely extensively on hydroelectric generation since during dry years there could be significant capacity shortages; there could be some mitigating measures to address this problem, but the issue bears further study.

It is likely that capacity reserves will be adequate to meet consumer demand when the electricity market first begins to operate under the proposed new structure. This will provide an initial cushion while demand responsiveness begins to emerge. However, we can expect those generators who fail to cover their fixed costs through pool prices and the CTC to close down. This could occur quite rapidly.

E. Conclusions and Recommendations

Location-Specific Pricing: The CPUC's Power Exchange pricing mechanism dulls the incentive for customers to act in an economically efficient way. The CPUC also chose not to preserve the opportunity for UDCs or DAs to act appropriately on their consumers' behalf. This lack of proper incentives will reduce some consumers' willingness to sign contracts with new generators, which will, in turn, reduce the number of investors willing to fund new, economical generation.

The staff has urged the CPUC to preserve at least the incentive for UDCs and DAs to act efficiently on their customers' behalf. The CPUC can accomplish this by retaining the decision on how to distribute Power Exchange revenue obligations within the State-jurisdictional arena. By so doing, the CPUC and individual municipal utilities can pass along the benefits of serving all customers who could be served by less expensive alternatives. We continue to support this position.

The WEPEX proposal further blunts the incentives associated with location-specific prices by computing intra-zonal congestion-management costs inefficiently. This, combined with the CPUC pricing approach, could seriously affect the incentive for both generators and consumers to act efficiently. The Commission and the CPUC should strongly oppose WEPEX intra-zonal pricing proposal.

Transmission-Congestion Contracts: In comments submitted in various proceedings associated with industry restructuring, the Commission has supported the rationale for ISO-administered TCCs. Staff believes that the Commission should continue to support this incentive mechanism. However, there are significant issues to be addressed before this mechanism can produce the desired effect. The Commission should urge the CPUC to direct utilities to begin the process of examining these issues.

Load Bidding: To address the potential for capacity shortages and their associated adverse impacts on consumers, the Commission should monitor generator retirements and load responsiveness as the new market begins to function. Given the preceding discussion, if the lack of effective incentives persists, the state should expect to encounter several problems which may require regulatory intervention to resolve:

Unless consumers face efficient, marginal-cost pricing, they lack the incentive to develop demand responsiveness. Likewise, unless UDCs and DAs face efficient, marginal-cost pricing, they also lack the incentive to act appropriately on behalf of their customers. These problems are worsened by the WEPEX proposal to dull the locational-price differences that emerge within pricing zones.

We need to support efficient, marginal-cost pricing to encourage efficient investment in plant, DSM (using the term in its broadest sense), and transmission upgrades. Using an administratively determined capacity payment may be a reasonable way to assure that existing generators receive sufficient compensation to remain in service while the state works through the uncertainties about demand bidding. In the meantime, it is important for the State to conduct load research to determine the level of demand responsiveness that might emerge in the near term. If this research determines that demand response is, or will soon be, present, the state can begin to rely on this customer-driven mechanism rather than an administratively determined reliability target.

WITNESS QUALIFICATIONS

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I have worked at the California Energy Commission since 1977. I am currently the Commission's Chief Resource Planner. I have served in that capacity since 1988 with special assignments from 1989 through 1992 on Integrated Resource Planning and as a Commissioner's adviser.

I have been an active participant in the WEPEX team meetings and in earlier Competitive Power Market Working Group team meetings in which many of the same issues were examined. As a resource planner and as a Commissioner's adviser, I was the Commission's chief witness on generation-need and transmission-policy issues.

I received a Bachelor of Arts degree in Economics from California State Univesity, Sacramento.